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Evolution of primary frequency control requirements in Great Britain with increasing wind generation

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Abstract

With the increase of renewable generating capacity following the ambitious targets set by many governments for the next decades, there will be major changes in power generation and challenges for balancing transmission grids. In particular, primary frequency control requirements will be increased following a potential reduction of system inertia.

An assessment of the frequency response reserve needed is made through use of a simple model of the Great Britain transmission grid for different loads and wind power penetration. This model analyses the effect of changing the system inertia and the effectiveness of standard frequency response as well as dynamic frequency control support.

It is observed that an increased wind power generation requires substantial additional reserves for primary frequency control if the wind turbines do not contribute to the overall system inertia. However, it is also shown that these reserves can be dramatically reduced if the system is provided with fast acting response by dynamic frequency control support.

Keywords: Reserves, wind power, frequency control, frequency stability, power system

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1. Introduction

Traditionally, electricity grids are dominated by synchronous generators linked directly to the grid, and the mechanical inertia in the rotating machinery provides inertia to the grid frequency such that imbalances in supply to demand result only in a relatively slow change of the grid frequency which can easily be corrected. However, with globally increasing contribution of power from wind and PV through inverters, this inertia is effectively reduced as inverters do not provide any intrinsic inertia. Furthermore, most renewable power can only be controlled through curtailing output, which is useful if supply exceeds demand, but not in the other case where demand exceeds supply. A critical case of the latter situation arises if there is a sudden loss of generation.

The British government (DECC) has set a target of delivering 15% of its energy demand from renewable energy sources by 2020 [1, 2]. This is dictated by the Climate Change Act of 2008 setting a target of 80% reduction of CO_2 emissions (compared to 1990) by 2050, with at least a 34% reduction by 2020 and 60% reduction by 2030. In particular, the UK government is confident to achieve a 30% electricity generation from renewable energy sources [2]. This means that the installed generating capacity is likely to change dramatically over the next years and even further by 2030. Based on different scenarios, it is expected that transmission connected variable renewable generation will exceed the minimum load (and possibly even peak load) by 2030 as shown in figure 1 (further details provided in table 1).

In all scenarios, the instant proportion of renewable generation on the grid, in particular wind power in the UK, will increase. Since the characteristics of this generation differs from conventional generation, it is important to study the need for changes in power system operation at times with high instant penetration level of wind power. As a reminder, the instant share of wind generation at time t is defined as the ratio of combined wind power fed into the network to the total output of all grid-connected generators at the particular point in time. This instant penetration level is key when assessing the impact of wind power generation on the grid.

One of the key challenges is to maintain the grid frequency within specified limits. In traditional large transmission systems, the combined electromechanical inertia of the rotating machinery directly linked to the grid provided frequency inertia which allowed enough time for corrective action [4, 5, 6]. The nature of both, the resource and the technology to convert wind

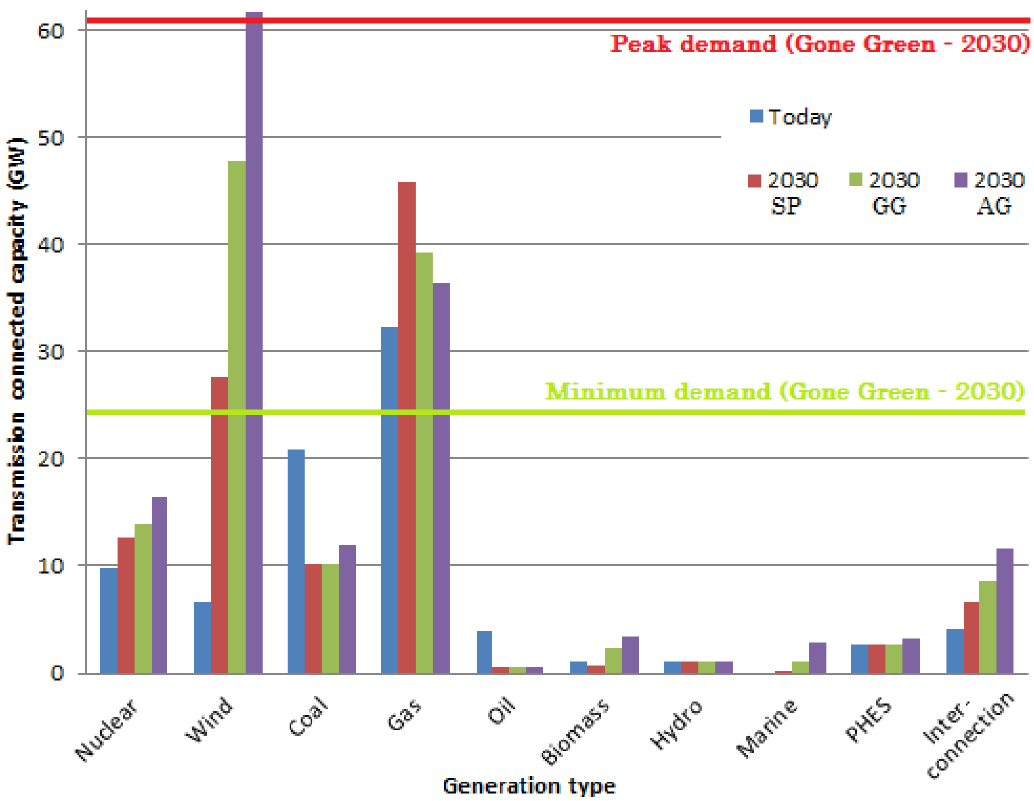

Figure 1: Evolution of transmission connected capacity in Great-Britain by 2030 under various scenarios (data: National Grid [3]).

power, do not necessarily contribute to that frequency inertia and additional reserve generation or control strategies have to be used [7, 8, 9, 10, 11]. The same also applies to other variable resources, such as PV [12].

When trying to reduce greenhouse gases emissions, not only generation directly feeding into the grid has to be considered, but also generation kept into reserve for system balance mechanism. In particular, part loaded conventional plants contributing to primary frequency control run at lower efficiencies, and the consequence is that the associated greenhouse gases emissions are increased [8]. It is therefore important to understand the effectiveness of frequency control strategies and their demand on the plant providing this to find ways to reduce their environmental impact as much as possible while providing security and quality of supply.

1.1. Aims and objectives

From all these impacts, this article focuses on the particular aspect of response capacity needed to cope with the loss of the largest generating unit on the UK transmission grid. This aspect of security of supply is particularly important for keeping the system operating within safe limits preventing blackouts due to cascading trip of generating units. With this focus in mind, the objectives of this work are to simulate and analyse the response of the grid following loss of generation under a range of demand and wind power conditions for a choice of frequency control strategies for the wind power. From these simulations, the required power level of response action to keep the grid frequency within the legal range is determined as the key measure.

The remainder of this section will first state the projected electricity generation targets and power quality constraints for the UK and then provide an overview over Great Britain's current power system and wind turbine generator technologies. Frequency regulation strategies and actions to ensure compliance with power quality constraints are introduced in §2. The model to investigate the response of the grid to primary frequency control actions is developed in §3. The simulation results are presented in §4, and conclusions drawn for the future of frequency regulation in §5.

1.2. Future electricity generation in Great Britain

National Grid has published three reference scenarios [3] for future electricity requirements in Great Britain by 2030:

Slow progression (SP): the economy is restarting slowly after the crisis, with environmental targets met late.

Gone green (GG): the economy is restarting slowly with environmental target met according to schedule.

Accelerated growth (AG): the economy is restarting fast with significant growth and focus on environmental targets being met on schedule.

Figure 1 and table 1 show the associated changes in generating capacity to be expected by 2030 according to these scenarios. These three scenarios form the basis of the load and wind power conditions for our model.

1.3. Frequency standards in Great Britain

The nominal value of the grid frequency on European grids including that of the UK is $f_0 = 50$ Hz. Frequency standards are described in National Grid's *Security and Quality of Supply Standard* [13]. In particular, two requirements are of particular interest for this study, namely those concerning the power frequency following a *normal* or *infrequent* loss of generation, which are classified according to the magnitude of loss of power [14]:

- Following a normal loss of generation, specified as 1,320 MW from April 2014, the frequency must not fall below 49.5 Hz.

- Following an infrequent loss of generation with a loss of 1,800 MW, the frequency must return above 49.5 Hz within 60 s.

In line with the study's aims, these two threshold values of loss of generation were used in the model to investigate the level of generation response required to comply with these regulations for ranges of load-wind power situations expected within the scenarios outlined in §1.2.

1.4. Great Britain's transmission grid

National Grid is responsible for the system operation in Great Britain, in accordance with the terms of the Transmission Licence granted by the British regulator OFGEM. This transmission system is linked to France, the Netherlands, Northern Ireland and the Republic of Ireland through DC links so that its synchronous zone is limited to the main island of Great Britain itself (and small neighbouring British isles such as the Hebrides and the Isle of Man).

Figure 2 shows typical demand profiles on the transmission grid (not including storage action adding to demand) over the course of the day and

Table 1: Predictions of installed transmission-connected capacity evolution (data: National Grid [3]).

Type	Scenario	Installed capacity (GW)		
		2013	2020	2030
Nuclear	SP	9.9	9.5	12.6
	GG		9.5	13.9
	AG		8.7	16.4
Conventional thermal	SP	57.8	57	57.2
	GG		55.6	52.3
	AG		57.4	52.3
Hydro	SP	1.1	1.1	1.1
	GG		1.1	1.1
	AG		1.1	1.1
Wind	SP	6.8	13.4	27.6
	GG		25.6	47.7
	AG		33.0	61.6
Pumped storage	SP	2.7	2.7	2.7
	GG		2.7	2.7
	AG		3.3	3.3
Inter-connection	SP	4.2	5.2	6.6
	GG		6.6	8.6
	AG		6.6	11.6
Total (transmission-connected)	SP	82.7	88.9	101.8
	GG		101.1	127.5
	AG		110.4	149.3

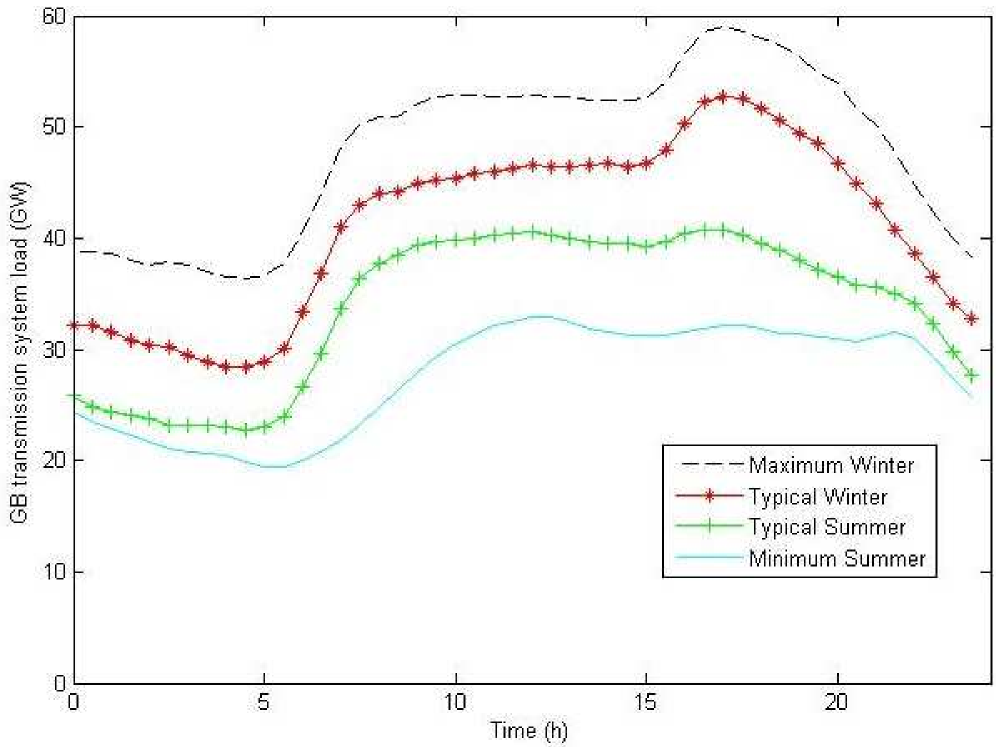

Figure 2: Typical transmission system load profiles on GB transmission grid in 2010-2011 (data: National Grid [15]).

Table 2: Evolution of minimum and peak demand [16].

		Demand (GW)	
Year	Scenario	Minimum	Peak
2013		23	57.7
2020	SP	23.1	57.8
	GG	23.1	57.6
	AG	23.4	58.5
2030	SP	22.7	56.6
	GG	24.3	60.7
	AG	26.3	65.7

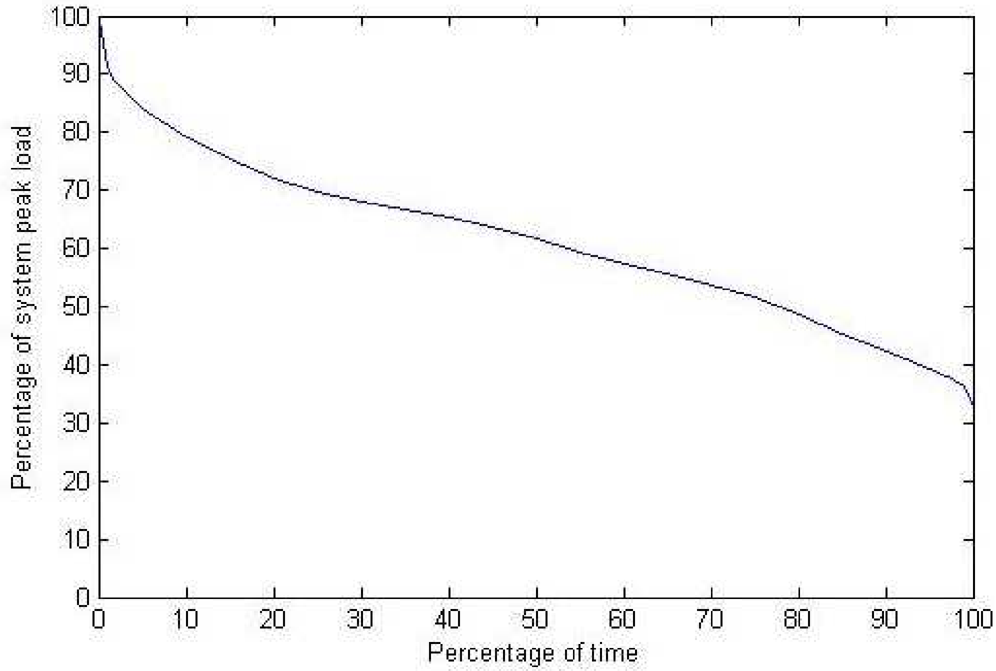

Figure 3: Load-duration curve for the GB transmission system in 2010-2011 (data: National Grid [15]).

the year. The peak load of a day is usually around 1.5 times the minimum load taking place at the early hours of a day.

Figure 3 shows the distribution of load throughout the year, so that for each load level the number of hours per year at which the system is operating at this load may be worked out. In particular, it shows that for around 50% of time, the load lies below 60% of peak load. It is therefore important to consider what happens at lower loads on the system. Minimum and peak system demand are expected to evolve according to the different scenarios. This evolution is detailed in table 2, where all values treat small embedded generation as negative load (so that it is subtracted from real load) in order to consider only transmission system load. Nevertheless, with the development of PHES and interconnector shown in table 1, there will be more room for differences between load and generation.

1.5. Wind turbine generator technologies

Currently, four main types of generators are common for wind energy converters, synchronous or asynchronous induction generators, doubly fed induction generators (DFIG), and fully rated converters (FRC) [5]. While the wind turbine market was in the past dominated by fixed-speed wind turbines with induction generators, almost all modern wind turbines have variable speed rotors and require DFIGs or FRCs. While the fixed-speed turbines can be directly linked to the grid and thereby contribute to frequency stability through their electro-mechanical inertia, variable-speed machines have many advantages. One of these is that they can optimise the aerodynamic conditions and thereby optimise the power output. There is also less stress on the mechanical components if the turbine can adjust its rotation rate to the wind conditions independently of the grid frequency, e.g. [17]. DFIG and FRC generators are decoupled from the grid through the use of back-to-back rectifier and inverter between the stator and the grid, which not only allows to optimise the aerodynamics but also control of the power factor. As the physical motion of the rotor is now decoupled from the grid, the rotor's inertia can no longer be used directly to provide inertia to the grid. However, it is possible to provide what is called *synthetic inertia*.

With the development of power electronics and increase in Transmission System Operators' (TSO) requirements for grid connection, there has been a dramatic shift in the turbine market towards variable speed wind turbines [18]. Even though the power electronics may represent around 7% of the cost of a turbine, they may capture as much as 5% more energy per year [19].

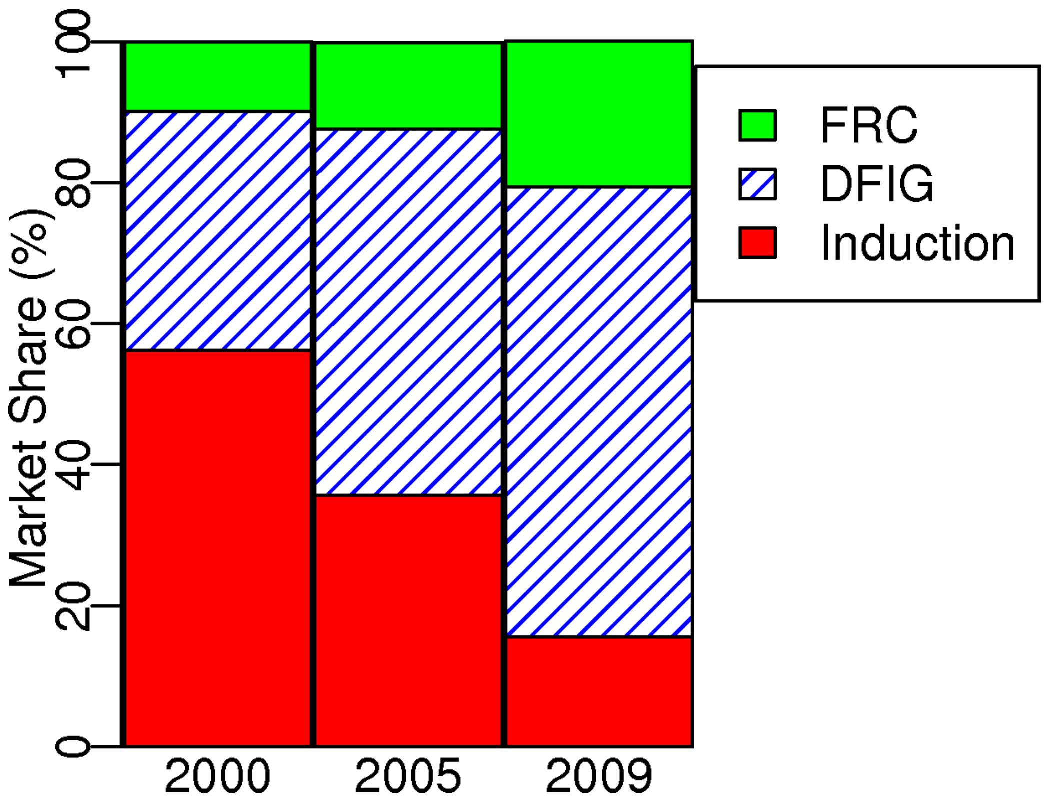

Figure 4: Evolution of WT generator types (data: [18]).

The evolution of the shares of different wind turbines technologies between 2000 and 2009 is given in figure 4. It shows a dramatic shift towards use of power electronics based turbines generators where DFIG and, more recently FRC, dominate the market.

2. Frequency control stages

The majority of generators used in conventional power plants are synchronous generators. For such generators, the frequency output delivered by the generator is proportional to the rotating speed of the rotor [5]:

$$f = \frac{p\,\omega_m}{4\pi} \tag{1}$$

Where ω_m is the rotating speed of the rotor (in rad s^{-1}) and p the number of poles of the generator (i.e. twice the number of pole pairs).

Whenever load exceeds generation, supplementary energy will be extracted from the kinetic energy of rotating parts in generators and these rotating parts slow down in response. Conversely, whenever generation exceeds load, kinetic energy will be added to the system and the rotors accelerate. For this reason, frequency is a key indicator of the real-time balance between supply and demand of active power on the grid. Its control is necessary at all times to ensure operation within reasonable and specified limits.

2.1. System inertia

The response of the grid frequency to the supply-demand balance is expressed as (adapted from [20]):

$$\frac{df}{dt} = \frac{\Delta P\, f_0}{2\, S_n H}, \tag{2}$$

where ΔP is the power imbalance (expressed in W) and defined as $\Delta P = P_{gen} - L_{sys}$, with P_{gen} the aggregated active power input of all generators and L_{sys} the demand, and $S_n H$ is the total system inertia. The system inertia determines the power system dynamics in response to a disturbance. While various formal descriptions are available for the inertia of individual generators or the whole system, the H factor (expressed in s or MW s/MVA) representation is used here, following e.g. [5, 21]:

$$H_i = \frac{E_{k,i}}{S_{n,i}}, \tag{3}$$

Table 3: Typical inertia constants for generators [8, 22].

Generator type	H constant (s)
Thermal 2 / 4 poles	2.5 – 6 / 4 – 10
Hydro	2 – 4
Wind (appropriate control [23])	2 – 6

where $E_{k,i}$ is the kinetic energy of rotors in the generator (in MJ) and $S_{n,i}$ is the apparent power output of the generator (in MVA). The system inertia is composed of the apparent power output of all generators $S_{n,i}$, each with their own inertial time scale H_i as

$$H = \frac{\sum_i S_{n,i} H_i}{\sum_i S_{n,i}}. \tag{4}$$

The inertia of a generator depends on the generator mass, shape and rotational speed (function of the frequency and number of poles) for directly coupled synchronous generators used in conventional power plants [5, 21, 22].

For power generator connected to the grid through DC converter, it is possible to mimic the behaviour of synchronous generation through appropriate controller action. This is known as *synthetic inertia* [20, 23] and can be used in wind turbines for example.

Examples of typical ranges for the inertial time constant H are given in table 3 and the influence of inertia on power system dynamics is shown in figure 5. There one can see that a lower inertia results in a faster and more pronounced drop of the grid frequency when the when a sudden loss of generation leads to a large negative power imbalance.

2.2. Load frequency sensitivity

Not only directly connected generators but also some loads, such as synchronous engines, vary their speed (and consequently load) in response to frequency changes. This behaviour is called *self-regulation of load* or *load frequency sensitivity* since this load change is opposed to the frequency change, and defined as [24, 8]:

$$K_L = \frac{\Delta L_{sys}/L_{sys}}{\Delta f/f_0} \tag{5}$$

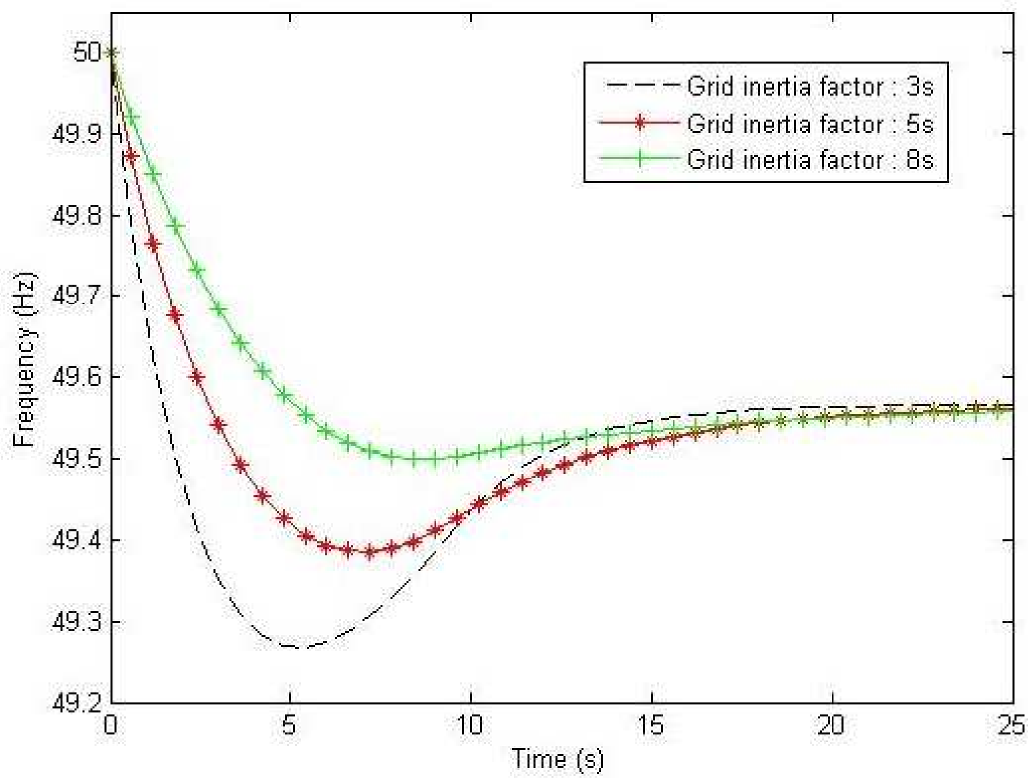

Figure 5: Influence of inertia on frequency response *ceteris paribus* (system with load of 30 GW, available PFR of 800 MW, K_L of 2 and for a loss of 1,320 MW at t=0).

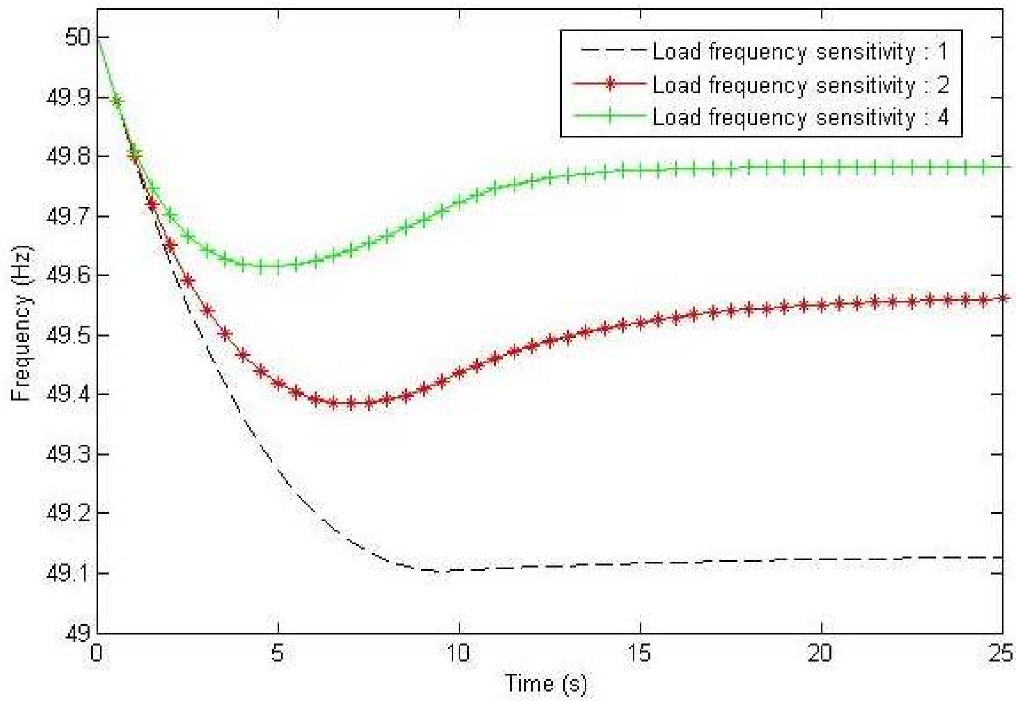

Figure 6: Influence of load frequency sensitivity on frequency response (Influence of inertia on frequency response *ceteris paribus* (system with load of 30 GW, available PFR of 800 MW, system inertia constant of 5s and for a loss of 1,320 MW at t=0).

Where $\Delta f = f_{qss} - f_0$ is the frequency deviation for the quasi-steady state frequency f_{qss} from the target frequency (50 Hz). While this self-regulation of load, K_L, is a dimensionless number, some authors use the pseudo-unit %MW/Hz (where 2%MW/Hz means that a drop of 1% in frequency causes a drop of 2% in the load).

The influence of K_L on the grid frequency is shown in figure 6. While this factor is highly dependent on the type of system and on the nature of loads connected, it is usually too small to provide full frequency regulation alone. For example, it is considered by TSOs in continental Europe to be in the range of 0.5 to 1[25] and in the range of 1.1 to 6 in the UK [8]).

2.3. Types of frequency control

Frequency control is commonly separated into three different types of control: primary, secondary, tertiary and time frequency control.

The only type of frequency control investigated in this study is primary frequency control. For completeness, the other types will be presented briefly to help understanding the basics of frequency regulation on a power system.

2.3.1. Primary frequency control

Primary frequency control is the fastest deployed type of frequency control. It is generally deployed within a few seconds for a duration of up to several minutes. This type of response is achieved through different mechanisms such as load control and turbine governor action.

Load control is a demand-side possibility, often based on centralised remote control, to regulate frequency. Some loads (such as refrigerators) may not need to be run constantly so that they may be shut down for a given period in order to contribute to frequency regulation without affecting the end user. Further studies of advanced complex dynamic control of large numbers of loads have proven the potential to add significant frequency stability to power networks [26, 27].

Turbine governor action happens in conventional thermal or hydro power generation. The frequency is automatically regulated using a device called governor which regulates the power input of the turbine (e.g. steam flow) according to the rotational speed in order to ensure stable operation of the generator [5, 28]. The governor action depends mainly on two parameters, the *dead band* and the *speed droop*.

The *dead band* of the governor determines the minimum amount of change in frequency needed before the governor action is activated. Some generating units may not participate to primary frequency control and their dead band would be set to a larger value to activate frequency control only for large disturbances [5]. As an example, the dead band of the governors installed in plants participating to primary frequency control on Great Britain's grid is ± 15 mHz[14].

The *speed droop* which is the ratio of the relative change in frequency to the relative change in power output [29] (expressed in %):

$$s_G = -\frac{\Delta f / f_0}{\Delta P_G / P_{G_n}}, \tag{6}$$

where f_0 is the target frequency, $\Delta f = f - f_0$ is the difference between system frequency and the target frequency, P_{G_n} is the rated active power output and $\Delta P_G = P_G - P_{G_n}$ is the difference between actual power output and rated power output. This droop is always positive to ensure stable operation and

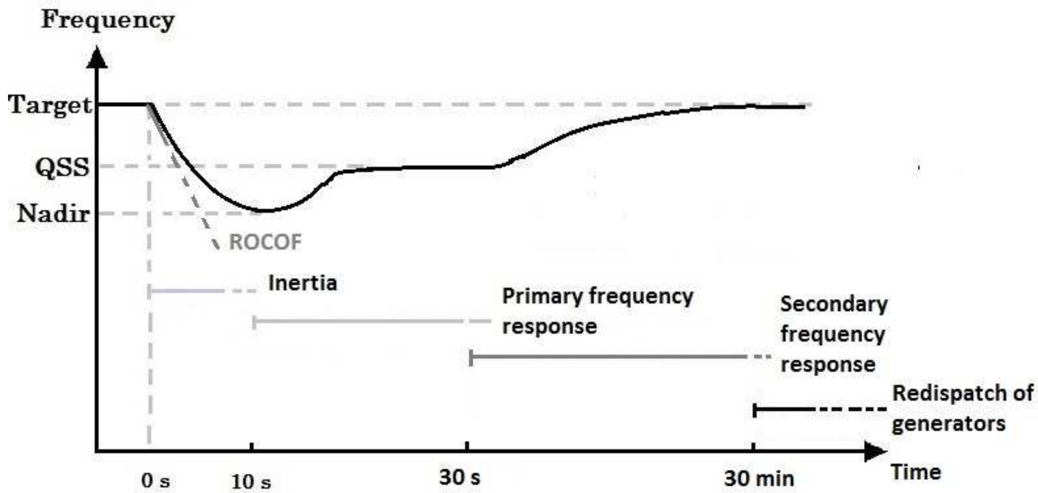

Figure 7: Summary of frequency control in Great-Britain.

is set to 4% in Great Britain for frequency responsive plants, although some hydropower plants may use a 1% droop [8].

2.3.2. Organisation of primary frequency control in Great Britain

Primary frequency control is organised in three different types of control on Great Britain's transmission grid: primary and secondary frequency response following loss of generation, and high frequency response following loss of load [14]. High frequency response is deployed within a 10 s window following a loss of load through progressively reducing plant output.

Primary frequency response is the fastest type of frequency response provided after a loss of generation. It must be released and ramped up to the required level within 10 s and then sustained for at least an additional 20 s. Secondary frequency response is released within 30 s and may be sustained for a further 30 minutes. Currently, both responses ancillary service are provided by coal, CCGT and hydropower plants [8].

2.3.3. Secondary, tertiary and time frequency control

Primary control actions are not designed to restore frequency to its target value without further action. Then, once primary frequency control has stabilised the frequency, secondary frequency is implemented to start bringing the frequency back to its target value. Each plant participating will operate within a certain range of power regulation that depends on its type.

In an interconnected system, the control of this response should be made in a centralised way to avoid undesirable power flows on tie-lines which could arise from compensation of changes in load or production in a different control area. However, several hierarchical levels of centralised control may be used in some systems, with a central coordinator dispatching control to the different subsystems where secondary control is operated in a decentralised way [29].

Tertiary frequency control follows the same aims and principles as secondary frequency control but operates on a longer time scale. It is achieved through different methods in the time frame of scheduling, such as (examples from [5]):

- connection or tripping of power stations or loads on the reserve of the tertiary control
- re-dispatch of generating units
- redistribution of secondary control generator output by adjustment of the reference value of generated power
- changes in the power interchange program

These types of frequency control will not be considered in this study which focuses on primary frequency control. Moreover, secondary frequency control is not implemented on Great Britain's grid [24], so that only tertiary frequency control is used to restore the frequency back to its target value.

For completeness, a different form of frequency control should be mentioned. Time frequency control, also known as *time error correction* or *electric clock time control*), is not used to ensure power quality but to ensure that timing devices based on grid voltage cycles remain 'on time'. This is made through adjustments of the system target frequency for long periods of time (in the range of several hours) in order to keep the mean value of frequency at 50 Hz [30]. Its necessity, however, is debated and it may disappear over the next years [31].

2.3.4. Dynamic Frequency Control Support

Dynamic Frequency Control Support (DFCS) is a system implemented on rather small island grid, such as some of the French islands, with low inertia [32, 33]. It has very short deployment times (around 1 s) since it is based on fast action from distributed energy storage systems. While traditional technologies were based on lead-acid or nickel cadmium batteries, the development of advanced flywheels, faster lithium ion batteries, and ultracapacitors now provides faster response to match the short time scales [32]. This approach has already reached the megawatt scale in Hawaii with a test system based on ultracapacitors [33, 34].

While some types of control are based on the same principle as the primary frequency control described in §2.3.1, they are only effective for small speed droops of up to 1 or 2%. Another option is based on the frequency time derivative, where power is released proportionally to the rate of change of frequency, df/dt. This has been suggested to be more able to cope with large disturbances, and has therefore been adopted in this study.

2.4. Contribution to frequency control from wind turbines

Wind turbines have demonstrated their potential to assist in frequency control through adjustment of active power output and has become a requirement in certain grid codes [35]. For example, Hydro-Québec (the TSO of Quebec) has set stringent requirements for wind farms which should provide '*at least the same inertial response as a power plant whose inertia (H) equals 3.5s*' [36].

Power electronics based wind turbines can provide synthetic inertia to a power system [20, 23, 37, 38, 39, 40, 41]. Contrary to synchronous or asynchronous induction generators, a drop in frequency does not automatically lead to kinetic energy being extracted from the rotor of wind turbines with DFIG or FRC generators, and some control has to be implemented to mimic the inertial behaviour by providing synthetic inertia. The typical inertia H constant of a wind turbine lies in the range $2-6$ s [38, 39], compared to $2-10$ s for conventional generation as shown in table 3.

The most straightforward turbine action in frequency control is only available if there is a loss of load, or excess generation. In that case, the turbine power output can be reduced through torque control by pitch adjustment [41, 42, 43]. Even so, the provision of such frequency response depends on the wind speed [43] and may therefore be complex to operate accurately. Unless wind turbines are routinely operating at sub-optimal conditions, this action is not a possibility in the converse case of loss of generation.

In the case of loss of generation, synthetic inertia can be released by extracting kinetic energy from the rotor by controlling the output of the inverter above the wind power input to the rotor, so that it would slow down until the power output of inverter is lowered to a level equalling the rotor wind power input). However, for wind speeds below the rated wind speed of the turbine, the rotation rate of the rotor optimises the power output for that wind speed. A reduction in rotor speed therefore leads to a reduction in the efficiency and potentially substantial loss in power generation. This loss may be as high as 40% of the power output when operating close to the rated wind speed [44]. For that reason, this action may worsen the imbalance more than it would actually help in restoring balance, and some TSOs are reluctant to make use of this synthetic inertia. At wind speeds above the rated wind speed, when turbines operate in limited torque mode to limit the output from the generator, it is possible to override the torque limitation for a brief period of time, so that the wind turbine generator provides power above the rated power output[43].

One option for utilising the inertia of the rotor without necessarily going too far below the optimum tip speed ratio is to operate the rotor at a rotation rate above the optimal tip speed ratio. In that case, the kinetic energy of the rotor could be used to provide temporary additional power and, at the same time, increase the power conversion of the wind energy as the efficiency of the rotor increases as the rotational speed gets closer to the optimal speed [9, 41]. In this case, the wind turbine contributes both to the total system inertia and to the primary frequency control.

3. Simulation model

To investigate the primary frequency response required to maintain the grid frequency following normal loss of generation within the limits stipulated by the UK grid code, a MATLAB/Simulink© was developed to solve equations (2) modified by the self-regulation of load, eq. (5), and assuming a power factor of around 1, $S_n = L_{sys}$, as

$$\frac{2H\ L_{sys}}{f_0^2}\ f\ \frac{df}{dt} = \Delta P \tag{7}$$

where ΔP is the difference between the generation and the system load. The initial condition is $f(t=0) = f_0$ and the generation is initially the balance of base load generation, wind power output and the remaining frequency-responsive generation less the normal loss of power (ΔP_n),

$$\Delta P(t=0) = P_{base} + P_{fr} + P_{Wind} - \Delta P_n - L_{sys} = -\Delta P_n$$

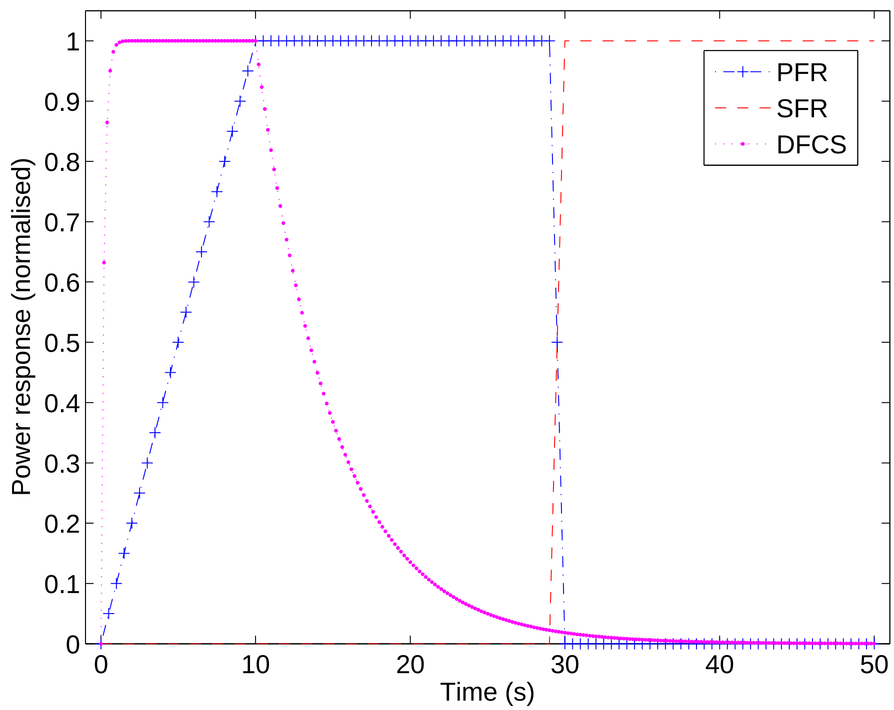

Figure 8: DFCS, PFR and SFR response models to a step change in frequency (Frequency change from 50 to 49.5 Hz at t=0, with full deployment of 1GW of DFCS, PFR and SFR).

As the simulation proceeds in time, this initial deficit in power is compensated by primary frequency response, $\mathcal{P}$, secondary frequency response, $\mathcal{S}$, and where included, dynamic frequency control support, $\mathcal{D}$, so that

$$\Delta P(t, f) = \Delta P(t = 0) + \mathcal{P}(t, f) + \mathcal{S}(t, f) + \mathcal{D}(t, f) - K_L \frac{f - f_0}{f_0} L_{sys}.$$

The forms of these three responsive actions are given in detail in the following section.

3.1. Model of frequency responses

The grid frequency model was initiated in a balanced state of a specified instantaneous load and wind penetration. At the time origin, $t = 0$, this state was perturbed by a sudden loss of generation of 1 320 MW (normal loss), followed by deployment of frequency response using PFR, SFR and, in some model settings, DFCS frequency response. The deployment strategy for these three responses are illustrated in figure 8 and described in detail in the following sections

3.1.1. Primary frequency response (PFR) model

Since the primary frequency reserve must be provided within $T_p = 10$ s of frequency drop and sustained for a further 20 s, it has been approximated by a linear increase from the time of loss of generation up to a target response within the first 10 s, followed by a constant response output until $T_f = 30$ s after the incident:

$$\mathcal{P}(f,t) = \begin{cases} \mathcal{P}_d(f) \times \frac{t}{T_p} & \text{if } t < T_p \\ \mathcal{P}_d(f) & \text{if } T_p \leq t < T_f \\ 0 & \text{if } t \geq T_f \end{cases} \tag{8}$$

with a target response action which is proportional to the frequency deviation, $f_0 - f$, up to all available power, P_{av}, utilised at the specified limit of $f_p = 49.5$Hz,

$$\mathcal{P}_d(f) = \begin{cases} 0 & \text{if } f \geq f_0 \\ \mathcal{P}_{av} \times \frac{f_0 - f}{f_0 - f_p} & \text{if } f_p < f < f_0 \\ \mathcal{P}_{av} & \text{if } f \leq f_p \end{cases} . \tag{9}$$

3.1.2. Secondary frequency response (SFR) model

Since the secondary frequency reserve must be provided within 30 s of frequency fall and sustained for a further half an hour (which exceeds the time simulated by the model), it has also been approximated by a linear ramp-up which is activated during the primary frequency control period after a time, $T_s = 29$ s, and reaches full deployment, S_d, at time $T_f = 30$ s, when all primary frequency control action is completed. Since our model does not go beyond the SFR time frame, we do not need to specify a maximum time for SFR deployment.

$$\mathcal{S}(Loss,t) = \begin{cases} 0 & \text{if } t < T_s \\ \mathcal{S}_d(Loss) \times \frac{t - T_s}{T_f - T_s} & \text{if } T_s \leq t \leq T_f \\ \mathcal{S}_d(Loss) & \text{if } t \geq T_f \end{cases} \tag{10}$$

The deployment strategy used in the model consists in releasing just enough SFR to ensure a quasi-steady state frequency of 49.5 Hz, so that :

$$\mathcal{S}_d(Loss) = \begin{cases} 0 & \text{if } Loss <= 0 \\ Loss - K_L L_{sys} \frac{\Delta f_{max}}{f_0} & \text{if } 0 < Loss \leq 1,800 MW \\ \mathcal{S}_{req} & \text{if } Loss \geq 1,800 MW \end{cases} \tag{11}$$

This SFR released where $\mathcal{S}req$ is the maximum available SFR requirement, dimensioned for compensation of an infrequent loss (1.8 GW) can be determined as [8]:

$$\mathcal{S}_{req} = \Delta P_i - K_L L_{sys}.\frac{\Delta f_{max}}{f_0} \tag{12}$$

where $\Delta P_i = 1,800$ MW is the power imbalance after infrequent (as the worst case must be chosen here) loss of generation, L_{sys} the load on the system, and $\Delta f_{max} = f_0 - f_{min}$ is the maximum quasi-steady-state (QSS) frequency deviation allowed in response to the loss considered. This is shown in figure 9 for the system characteristics investigated here.

3.1.3. Dynamic Frequency Control Support (DFCS) model

A DFCS system similar to that used for island grids with low inertia was also tested in this study to evaluate the potential reduction in primary frequency requirements. The power output through DFCS is modelled by:

$$\mathcal{D}(f,t) = \begin{cases} (1 - e^{-\frac{t}{\tau_u}})\, \mathcal{D}_d(f) & \text{if } t < T_0 \\ e^{-\frac{t-T_0}{\tau_d}}\, \mathcal{D}_d(f) & \text{if } t \geqslant T_0 \end{cases} \tag{13}$$

where $T_0 = 10s$, $\tau_u = 0.2s$, $\tau_d = 5s$ and

$$\mathcal{D}_d(f) = \begin{cases} 0 & \text{if } R < R_{min} \\ \mathcal{D}_{av} \frac{R}{R_{max}} & \text{if } R_{min} \leq R \leq R_{max} \\ \mathcal{D}_{av} & \text{if } R > R_{max} \end{cases} \tag{14}$$

where the deployment of the DFCS reserve ($\mathcal{D}_{av} = 500MW$ is considered here) is controlled by the highest magnitude of the (negative) rate of change

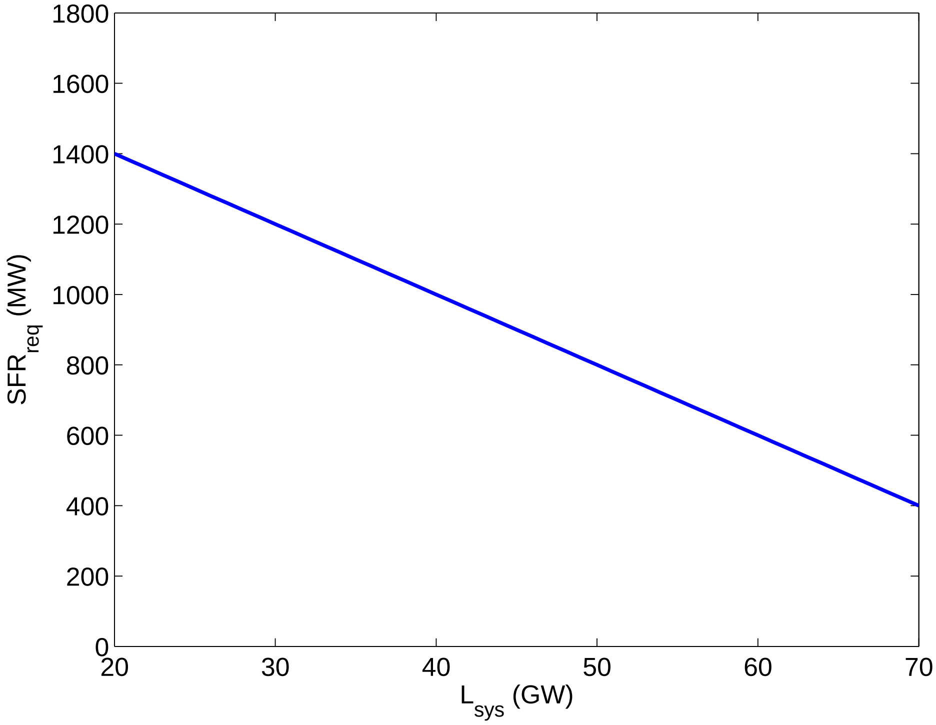

Figure 9: Variation of secondary frequency response requirements with load.

Table 4: Model parameters.

Parameter			Value	
System load		L_{sys}	20 to 70	GW
Wind power output		P_{wind}	0 to 50	GW
Base load generation		P_{base}	10	GW
Magnitude of normal loss	[14]	ΔP_n	1,320	MW
Magnitude of infrequent loss	[14]	ΔP_i	1,800	MW
Inertia		H		
- Non frequency responsive (base load)	[45]	H_n	4	s
- Frequency responsive generation	[45]	H_r	6	s
- Wind power inertia		H_w	none or 4	s
Load frequency sensitivity	[8]	K_L	2	

of frequency during the frequency fall (within a band specified by R_{max} and R_{min}) :

$$R = \max\left(-df/dt\right) \tag{15}$$

The values used for the parameters were determined based on typical response times presented in the literature [32, 33] and empirical adjustments after some experience with the model and are listed in §3.2 for two DFCS scenarios presented here.

3.2. Model parameters and scenarios

The parameters used in the model are summarised in table 4. Only transmission connected capacity and transmission system load were considered in the current set up. While this is a limitation of the model for future scenarios where substantial frequency response could be provided by embedded generation and micro-generation at the distribution level over the next years, this can be incorporated in a refinement of this model.

The model was used for a parametric analysis exploring the expected range of system load and installed wind capacity as listed in Table 4. A suitable balance of non-frequency responsive base generation, frequency responsive conventional generation and wind power was analysed in terms of required frequency response generation to provide frequency control within the stipulated constraints. With a base load of 10 GW, a physically meaningful wind power output is the remainder up to the current load, with a limit set at 50 GW. The corresponding frequency responsive conventional generation at the beginning of the simulation is then $P_{fr} = L_{sys} - P_{base} - P_{wind} - \Delta P$.

To estimate the effect of wind power on the system frequency, three options of frequency control from wind power were explored in four scenarios:

Scenario 1, standard frequency control: Inertial control is implemented in wind farms using $H = 4$s, which is a reasonable estimate for power inertial capability which is stated to be in the range from 2 s to 6 s [23, 38]. As this inertia time constant is the same as for the conventional non-frequency responsive generation, this scenario can be seen as the baseline. In this case, no DFCS is considered.

Scenario 2, No frequency control from wind: No inertial control is provided by wind turbines. No DFCS contribution is made.

Scenario 3, Dynamic Frequency Control Support: No inertial control is provided by wind turbines but 500 MW of DFCS is installed to provide fast short-term response if the rate of change of the frequency at the point of loss of generation exceeds $R_{min} = 0.0875$Hz/s with a full deployment of $\mathcal{D}_{av} = 500\ MW$ at $R_{max} = 0.35$Hz/s.

4. Results

This section presents the results of the simulation using the model developed above, the response requirements (PFR, SFR) under our scenarios are developed together with an evaluation of the impact of implementing DFCS on the amount of PFR needed. The model described in §3 was applied with incrementally increasing available primary and secondary frequency response, $\mathcal{P}_{av}$ and $\mathcal{S}_{av}$ respectively, until the frequency recovered sufficiently to comply with the imposed limits (cf. 1.3). Figures 10 to 15 present the results in the form of contour plots for pairs of Load and Wind power output. Since there is always a base provision of $P_{base} = 10$ GW, only pairs with $L_{sys} >= P_{base} - P_{wind}$ are physically valid situations, resulting in the triangular shape seen in these figures. The missing contour lines near that edge are a result of exploring the available space in steps of wind power and system loads determined by the available computing resources.

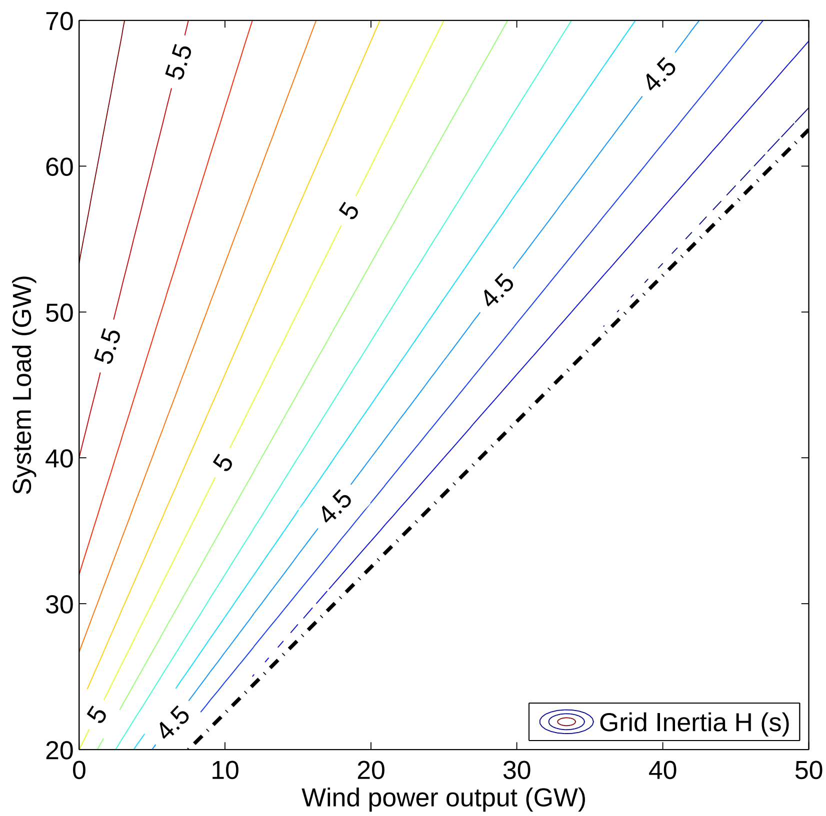

Figure 10: Scenario 1 - Grid inertia (H factor) variations with load and wind production.

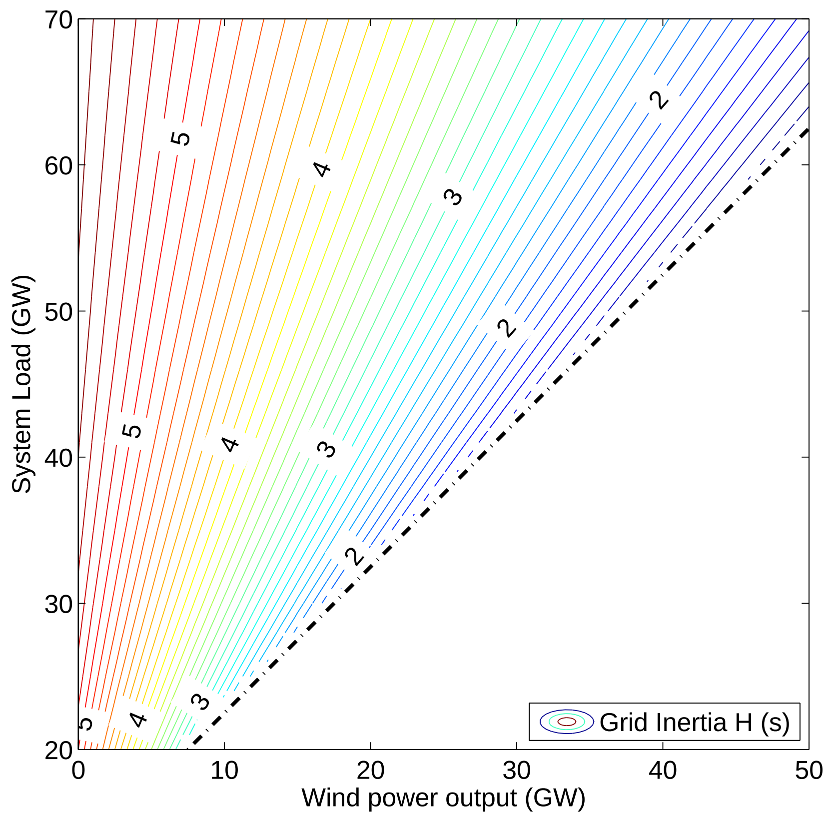

Figure 11: Scenario 2 and 3 - Grid inertia (H factor) variations with load and wind production.

4.1. Evolution of inertia

The values for H_{grid}, the grid inertia, were calculated using eq.(4) for each of the scenarios, assuming that the apparent power can be approximated by the load (i.e., power factor ≈ 1). The inertias for scenario 3 are identical to those of scenario 2 at the same load and supply conditions since wind turbines are not contributing to the inertia in either case. In scenario 1, as shown on figure 10, the grid inertia (H_{grid}) varies in the range from 4 to 5.7 s decreasing as load decreases and/or wind increases, where at high contribution from frequency responsive traditional generation (high L_{sys} and low P_{wind}) approaches 6 s corresponding to H_r, the inertia from that type of generation, while at high contribution from base generation and wind, the inertia tends to 4 s, corresponding to their respective individual inertia constants, H_n and H_w.

In scenarios 2 and 3, H_{grid} remains in the range between 4 and 6 s only if the wind power contribution is less than around 25% of the system load. For higher instant wind penetration, the grid inertia decreases progressively to around 1 s when wind power has replaced most frequency responsive generation. This dramatic drop in inertia with increased instant penetration of wind generation, will lead to a very high rate of change of frequency (ROCOF) in the event of loss of generation, which justifies the study of DFCS contribution.

4.2. Primary frequency response requirements without DFCS

The PFR requirement for the three scenarios is shown in figures 12 to 15, respectively. In the baseline scenario in figure 12, the need for PFR is primarily determined by the system load, especially when the load is high. This is seen by the almost horizontal contour lines. As the system load reduces, the PFR requirement increases progressively from around 11 MW at $L_{sys} = 70$ GW to over 3,000 MW when the system load is around 20 GW. Once the wind power contribution is no longer a small contribution to the supply, the PFR requirement also increases in line with the Wind power contribution.

In scenario 2 in figure 13, when the wind turbines do not contribute to the system inertia and the inertia therefore drops at high wind penetration, the PFR requirement is affected much more strongly by the instant wind power penetration. It not only rises to much higher levels, approaching 5 GW at low system load, but the instant wind power penetration pushes the requirement up much stronger.

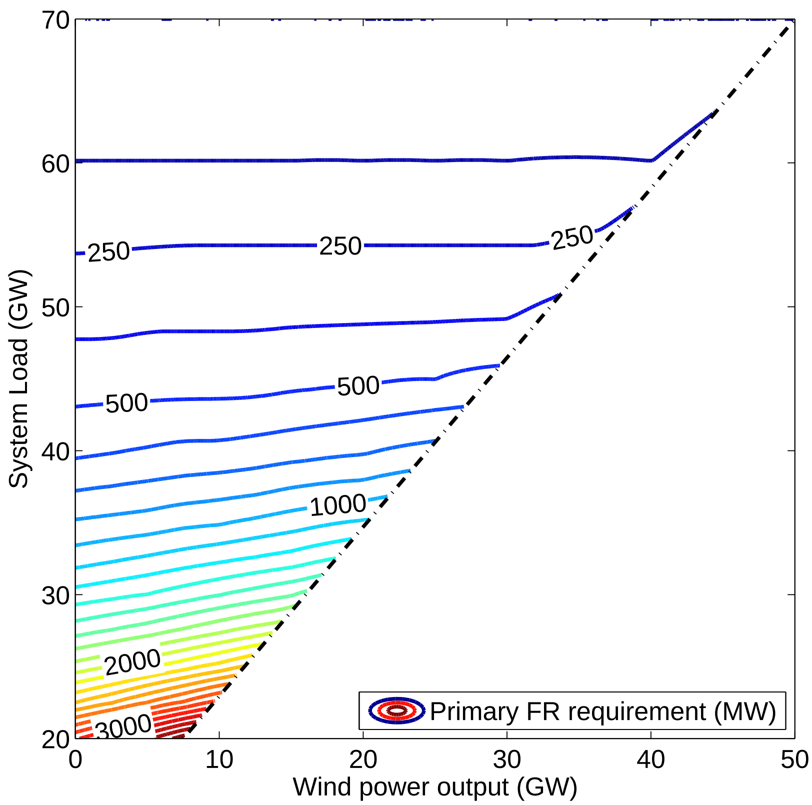

Figure 12: Scenario 1 - Variations of primary frequency response requirements with load and wind production (contour plot).

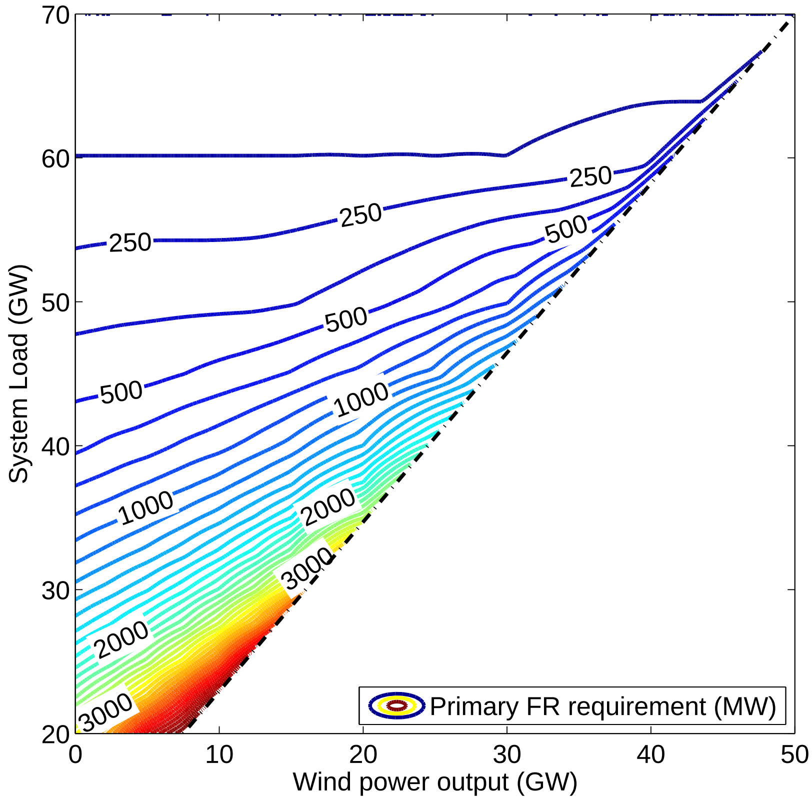

Figure 13: Scenario 2 - Variations of primary frequency response requirements with load and wind production (contour plot).

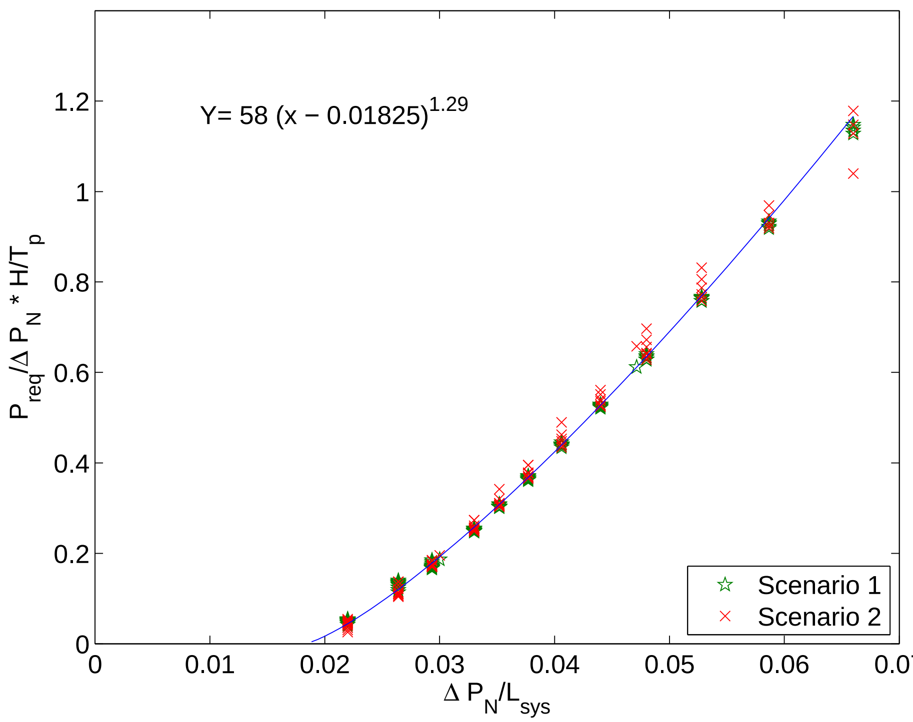

Figure 14: Primary frequency requirement for scenarios 1 and 2 in re-scaled variables of the product of PFR requirement with system inertia versus relative magnitude of loss of generation.

For example, while in scenario 1 a level of 1 GW PFR was required for a system load of 34 GW at no wind contribution, the level only rises to only 1.25 GW at 50% wind contribution to the same load. Conversely, a 1 GW PFR reserve is sufficient for 50% wind penetration at a system load of 35 GW. That same PFR reserve of 1 GW operating in scenario 2 is only sufficient for 50% wind penetration when the system load exceeds 40 GW, while a 50% wind contribution at a system load of 34 GW requires a PFR reserve of 2 GW.

As the response strategy for scenarios 1 and 2 are identical but respond to systems with a different system inertia, there should be a single description of the PFR requirement using suitably scaled variables. Guided by equations (4), (6), and the response strategy outlined in eq.(8), the PFR requirement and the system load (as a representative of S_n) were both scaled by the normal loss of generation (i.e. 1,300 MW) and the system inertia was scaled by the response for reaching full deployment of the reserve, T_p in eq.(8). Using these variables, it was found that both scenarios collapse onto a common curve when the independent variable is the relative magnitude of the loss of generation to the system load, $\Delta P_n/L_{sys}$, and the dependent variable the product of the relative required reserve, $\mathcal{P}_{req}/\Delta P_n$, with the rescaled system inertia, H/T_p, as shown in figure 14, where the green stars are for scenario 1 and the red crosses for scenario 2.

Above a threshold value of the magnitude of loss of generation, the PFR requirement increases with the proportion of the loss of generation to the system load. This threshold value was determined from the data to be 0.0185 ± 0.0005, meaning that the PFR reserve is only required when the loss of generation exceeds approximately 1.85% of the system load. Above that threshold, the requirement was found to increase slightly faster than linear, where a linear regression of the form $\ln y = b + m(x - x_0)$ found the best-fit curve as

$$\frac{\mathcal{P}_{req}}{\Delta P_n} = A\,\frac{T_p}{H}\,\left(\frac{\Delta P_n}{L_{sys}} - \Pi_0\right)^q \tag{16}$$

with $A = 58 \pm 2$, $\Pi_0 = 0.01825 \pm 0.0005$, $q = 1.29 \pm 0.02$, and a correlation coefficient of $r^2 = 0.991$. This line is shown as the solid blue line in figure 14. As eq.(6) is inversely proportional to the system inertia, it is not surprising that eq.(16) is inversely proportional to the system inertia. The result that the PFR requirement rises faster than linear can be explained by the fact that progressively more power is needed to not only make up for the loss of generation but also to recover the frequency from the level to which it had dropped before the PFR was fully deployed to a level from where the secondary frequency control can return the system to its target state. One would therefore expect that the exponent in eq.(16) will depend on the response time of the frequency control actions and that a much earlier or faster deployment of frequency control support could reduce the PFR requirements especially when the loss of generation is a relatively large fraction of the total generation. Equation (16) curve can now be used to benchmark alternative frequency control strategies such as DFCS which is designed to act very quickly.

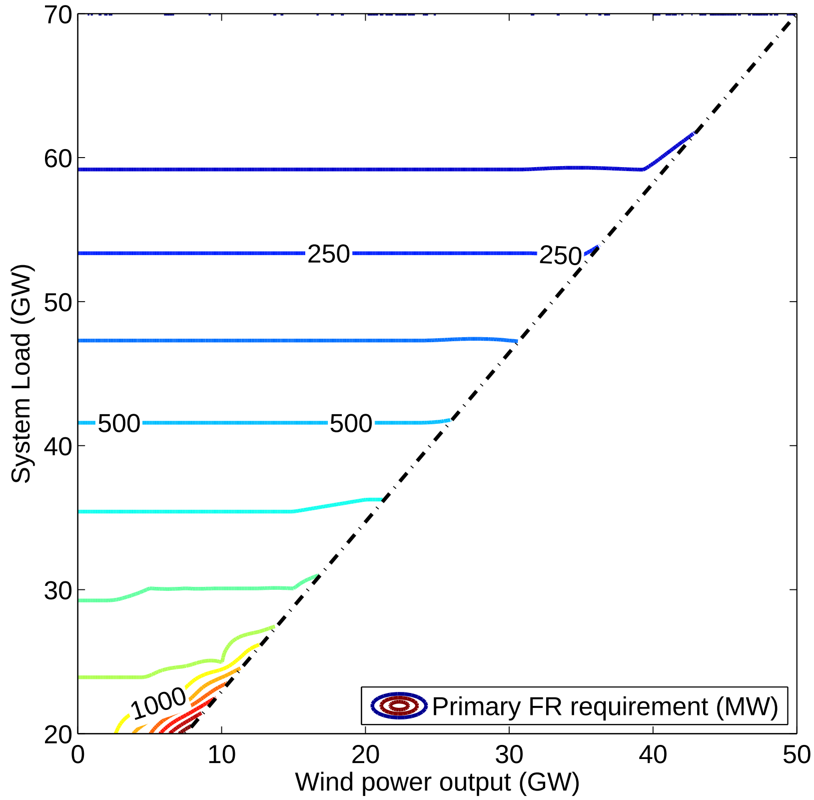

Figure 15: Scenario 3 - Variation of additional primary frequency response requirements in the presence of 500 MW DFCS against system load and wind production.

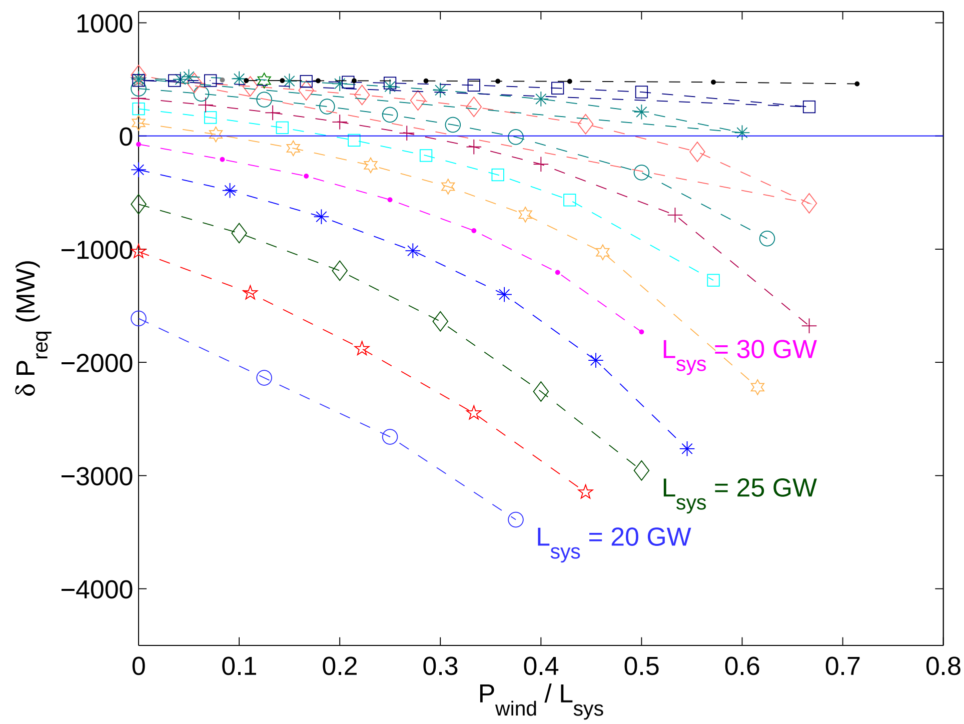

Figure 16: Scenario 3 - Change in total PFR requirement compared to benchmark against wind penetration.

4.3. Dynamic Frequency Control Support

To quantify if there is an actual reduction in overall PFR reserve requirement compared to standard primary frequency control, the change in total PFR requirement against the benchmark from eq.(16) is shown in figure 16. Note that the total requirement for scenario 3 consists of the 500 MW DFCS and the additional PFR requirement from figure 15. At low system load, the activation of DFCS not only equals the standard PFR requirement – where the improvement jumps to the zero line at the first activation – but rapidly reduces the PFR requirements substantially.

These results demonstrate that DFCS has the potential to reduce the PFR requirement especially in cases where generation with no or little inertia contribute substantially to the total generation in situations when the loss of generation is a small percentage of generation ($\lesssim 4\%$).

The results for Scenario 3 are shown in figure 15, where two key features are clearly shown. Firstly, the deployment of the DFCS reserve at much smaller rate of change of frequency has removed the split between DFCS involvement and no benefit which was observed in scenario 3 and restricted the DFCS benefit to a small band. Secondly, the maximum additional PFR requirement is now substantially reduced not only compared to scenario 2 (fig. 13) but even to scenario 1 (fig. 12) where the wind turbines fully contribute to the system inertia at the levels of conventional generators. Here, the maximum additional PFR is 1,240 MW at minimum load and maximum wind analysed compared to a PFR of 3,157 MW required under the same conditions in scenario 2 (and 3,567 MW in scenario 2). In these extreme conditions, the investment of 500 MW DFCS reserve is expected to be small compared to the savings in traditional PFR reserve requirements.

The overall benefit of DFCS in scenario 3 is shown in figure 17, where the change in total requirement (DFCS plus additional PFR) compared to the benchmark from eq.16) against that benchmark. Except for a small dead band where the benchmark requirement is near zero and the installed 500 MW DFCS results in a constant offset, the results are fully consistent with a linear change with the benchmark requirement as

$$PFR_{req,DFCS} - \mathcal{P}_{req,0} = \mathcal{D}_0 + \mathcal{P}_0 - \tilde{m}\mathcal{P}_{req,0}$$

where the total PFR requirement consists of the sum of DFCS, $\mathcal{D}_0$, and conventional PFR, $\mathcal{P}_{req}$, with $\mathcal{D}_0 = 500\text{MW}$, $\mathcal{P}_0 = 321 \pm 25\text{MW}$, $\tilde{m} = 0.810 \pm 0.011$, and a correlation coefficient of $r^2 = 0.986$ for the DFCS parameters

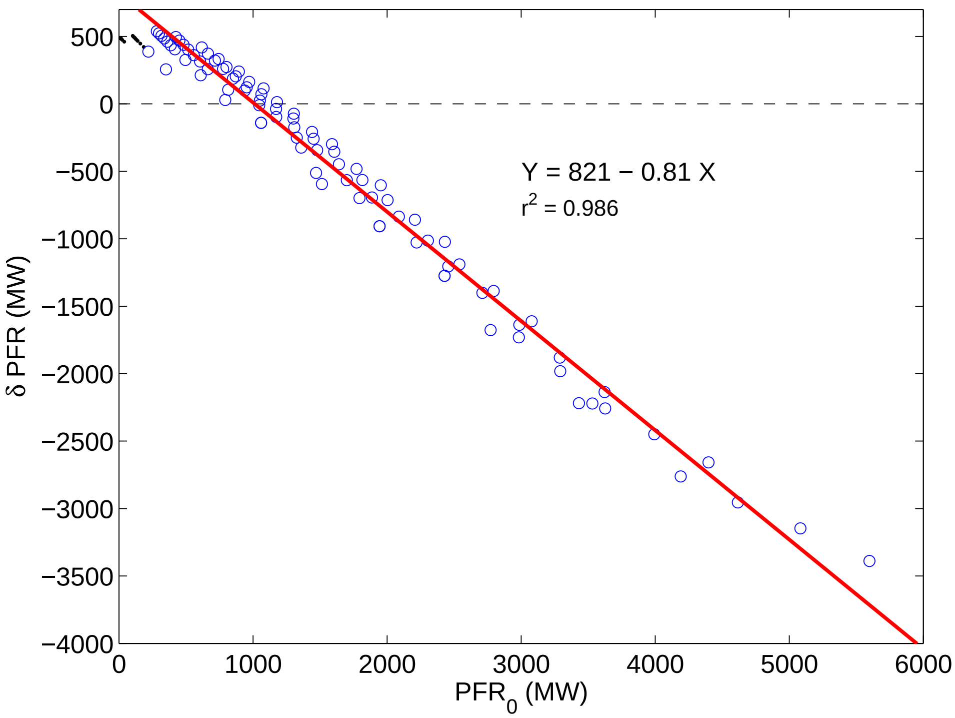

Figure 17: Scenario 3 - Change in total PFR requirement compared to benchmark against the benchmark.

used in Scenario 3. This can be rephrased in the additional traditional PFR requirement as

$$\mathcal{P}_{req} = \mathcal{P}_0 + m\mathcal{P}_{req,0} \tag{17}$$

with $m = 0.190 \pm 0.011$. In that case, the use of 500 MW DCFS leads to a net reduction in total primary frequency requirements from DCFS and conventional resource combined when the conventional PFR requirement is 1,013 MW.

5. Discussions and conclusion

This study has shown that a dramatic increase in primary frequency response requirements will be needed at low load levels with high wind production unless inertial control of wind turbines or large scale DFCS system is implemented in transmission networks of the size and nature as that of Great Britain. As the response of the system frequency depends directly on the system inertia and the speed with which it responds to changes in frequency, the PFR requirements are equally determined by both the grid inertia and the speed of response by the reserve.

The current model developed has a number of constraints ranging from general explicit and implicit assumptions to the range of parameter values investigated. It is important to keep these in mind when considering the results of the study.

One of the fixed parameters was the presence of minimum base-load generation of 10 GW with an inertia of 4 s. This choice has excluded possible future '100% Renewables' scenarios. While such scenarios are currently remote, it would be useful to extend the parameter range to include them in future work. In general, the model has simplified the actual generation mix by only two types with representative values of their inertia as plant inertia is confidential data for most of them in the UK. While this is a gross simplification, the result that the frequency behaviour following loss of generation can be expressed as a function of the magnitude of the relative loss and total system inertia alone, justifies this choice and is not expected to pose a serious limitation to this model.

Similarly, a single response behaviour for all combined PFR had to be assumed, and likewise for SFR and DFCS. The linear increase models for PFR and SFR may oversimplify the problem. However, in a simple model of generation with little data publicly available, they were considered as the most appropriate for a first simple assessment. For a more precise assessment, a model taking into account plant response through speed droop (by plant type) and based upon potential instant mixes for power generation and backup would be needed. This would actually increase the complexity of the model and the data required much further (involving some commercially sensitive data). A first step to investigate the actual need for such a model refinement would be to assess the sensitivity of the results to the deployment strategy in three particular steps; first by testing a slightly faster PFR deployment (for example within $T_p = 8$ and 9 s rather than 10 s), secondly by deploying faster than linear (e.g., proportional to $\sqrt{t/T_p}$) or slower than linear (e.g., $\propto (t/T_p)^2$), and thirdly by splitting the currently single PFR reserve into two kinds of plant with different inertia and response speed.

5.1. Suggested evolution of the infrastructure

Given the results of the study, there is an interest from both, an economical and environmental point of view, in studying the benefits from implementing DFCS on a large scale in transmission systems with a more precise model.

Given that the highest PFR requirement occur at low load, when the electricity spot price is low, the use of increasing the load by operating PHES in pumping mode and by exporting through interconnectors is economically attractive. If there is spare capacity in the reservoirs and demand from the other networks on the interconnector, this would artificially increase the system load and thereby reduce the PFR requirement. This poses the question to be investigated separately, namely to assess whether current or potential PHES energy capacities or interconnector demand are sufficient to provide this service under current or expected low-load conditions.

Last but not least, as the wind capacity increases and the system develops towards more sustainability, there will be a need for contribution from wind turbines to frequency control (unless large scale DFCS is implemented). For the UK grid, this is not ensured by the time of writing for two reasons; from a UK market point of view, Renewable Obligations push wind generators to produce as much as possible irrespective of the consequences; from a technological point of view or grid operation point of view, the current UK grid code does not provide advanced specific requirements for wind farms and relies on market structure for balancing services.

5.2. Further considerations

This study raised many questions for the future of frequency regulation in power systems developing towards more sustainability and has identified a number of investigations as immediate steps. In addition, the costs of different options should be investigated choose between large scale deployment of DFCS, inertial contribution from wind turbines, or higher conventional PFR requirements. For these options, environmental impacts, in particularly greenhouse gas emissions, should also be assessed.

Another aspect that may require more research is the improvement in load frequency response assessment and estimation, which as shown in [8] would help to reduce both PFR and SFR requirements resulting in reduced environmental impacts and expenses.

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